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UTILITY FLUE GAS DESULFURIZATION TECHNOLOGY AND COSTS

by

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16. ABSTRACT The paper is an overview of utility flue gas desulfurization (FGD) technology and costs. FGD systems can be classified as either: (1) systems in which the sulfur product generated through a scrubbing or adsorption operation is disposed of as waste (throwaway product system), or (2) those in which the sulfur product (e.g., sulfuric acid) is marketed (salable product systems). Although over 50 processes have been tested at bench scale or larger, the number of commercially significant processes is considerable smaller. The two commercially offered throwaway and salable product systems that are considered to be the most important for near-term (through 1990) SO2 control are: throwaway product systems--lime and limestone scrubbing (both sludge and gypsum variations) and dual (double) alkali; and salable product systems--magnesium oxide scrubbing and Wellman-Lord (sodium sulfite scrubbing). Other potentially important systems which are close to commercialization include dry scrubbing, seawater scrubbing, carbon adsorption, and copper oxide adsorption. To put FGD costs in perspective, it is useful to compare them to costs for coal-fired power plants. The capital cost and annual revenue requirement for such an uncontrolled plant are estimated at $710/kW and 39 mills/kWh in 1979 $, respectively. Comparable FGD controlled costs are 13 and 11 percent, respectively.

17. KEY WORDS AND DOCUMENT ANALYSIS		
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INTRODUCTION

Sulfur oxides are air pollutants deleterious to human health and are harmful to vegetation, buildings, and materials. Analyses of numerous epidemiological studies clearly indicate an association between air pollution, as measured by SO_2 concentration, and health effects of varying severities, particularly among the most susceptible elements of the population.

The current environmental driving force for sulfur oxide control is the Clean Air Act, amended in 1977, which created a schedule to decrease SO_2 emissions from power plants and other major sources for both new and existing facilities. The current New Source Performance Standard (NSPS) calls for from 70 to 90 percent SO_2 control for all new coal-fired facilities with the higher level of controls associated with high-sulfur coal. In no cases can emissions of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) be exceeded. This mandates application of control technology to new utility boilers burning both high- and low-sulfur coal.

These standards apply to power plants for which construction or modification commenced after September 19, 1978, and are based on commercially available technology taking into account cost. Coal-fired steam generators whose construction or modification commenced after August 17, 1971, but before September 19, 1978, are subject to NSPS requiring maximum SO_2 emissions of 520 ng/J but no percentage removal requirements.

The Clean Air Act amendments indirectly provide for control of existing power plants because State Implementation Plans (SIPs) were required for each state which include a control strategy for ensuring maintenance of the promulgated ambient air quality standards for sulfur oxides and other regulated pollutants. To meet the ambient SO_2 standards, it is necessary to limit the emissions of existing power plants in many of the 247 air quality control regions in many of the states.

ALTERNATIVES FOR FLUE GAS DESULFURIZATION

Within the next 5 years, the following options can provide for sulfur oxide control for coal-to-electricity systems: utilization of naturally occurring low-sulfur coal, physical coal cleaning, and flue gas desulfurization (FGD).

In addition, the following emerging technologies are in the development stage and may play a significant role in the post-1990 period: fluidized-bed combustion (atmospheric and pressurized), coal gasification, and coal liquefaction.

Naturally occurring low-sulfur coal is the most straightforward control option. Unfortunately, projected production capacity is limited, and most low-sulfur coal reserves are in the West, far away from Midwestern and Eastern requirements. Utilization of low-sulfur coal east of the Mississippi leads to substantial transportation costs, yielding overall power production costs comparable to the use of FGD with local high-sulfur coals. Also, the current utility NSPS precludes the use of low-sulfur coal without additional sulfur removal in light of the aforementioned 70 to 90 percent control requirement.

Physical coal cleaning utilizes differences in physical properties (e.g., specific gravity) between inorganic pyritic sulfur and other coal constituents. Coals vary widely in the pyritic content (from about 20 to 80 percent of the total sulfur content); organic sulfur and sulfate comprise the remaining portion of the sulfur. Coal cleaning technology is relatively simple and low in both capital cost and annual revenue requirements. Up to 80 percent of the pyritic sulfur can be removed by physical removal techniques. As with naturally occurring low-sulfur coal, coal cleaning cannot generally be utilized alone to meet the current NSPS percentage removal requirements. It should be noted that the combination of coal cleaning and FGD can substantially lower costs compared to FGD alone for certain applications.

In light of the limitations of the low-sulfur coal and coal cleaning options, FGD technology provides the only means of control of new utility sources, inasmuch as it is the only option commercially available by which it is possible to reduce sulfur oxide emissions sufficiently to comply with the current NSPS promulgated under the Clean Air Act. However, for less stringent control requirements for certain existing sources, low sulfur coal and coal cleaning are viable options.

HISTORY OF FGD

The first commercial application of FGD to power plant sulfur oxide control was in the U.K. in the early 1930s. The Battersea A power plant (228 MW) of the London Power Co., London, U.K., began flue gas washing in 1933. The process utilized wet scrubbing with alkaline Thames River water. The spent liquor was discharged back into the Thames after removal of solids and oxidation. The FGD system operated successfully at up to 95 percent SO_2 removal efficiency until the Battersea A power plant closed down in 1975. A similar FGD system operated on the Battersea B power plant (245 MW) between 1949 and 1969, when FGD operation was temporarily suspended because of adverse effects on the Thames water quality.

The ICI Howden process, also developed in the U.K., was developed to avoid discharging scrubber effluent into the Thames. This technology was the precursor to current lime and limestone wet scrubbing technology in wide use today. The waste sludge produced was barged to the sea for dumping. This process was applied to the Swansea power plant in 1935 and the Fulham power plant in 1937. These systems operated successfully until early World War II, when they were shut down since the steam plumes marked easy targets for enemy bombers.

The next FGD unit was installed at the Electrolytic Zinc Co. in Tasmania in 1949. Tidal water was used there as the absorbent for SO_2 from smelter gas.

In 1952 the first unit of the new oil-fired Bankside Power Station in London, U.K., was commissioned. The FGD system is an improved version of the Battersea system, using water from the Thames. This system, which had a 98 percent removal efficiency and capacity of 240 MW, was recently retired.

The 1950s and 1960s were a time of laboratory and pilot plant investigations of new processes. During the 1950s, the Tennessee Valley Authority (TVA) (U.S.) experimented with lime and limestone scrubbing systems, both dry and wet, and dilute acid processes; in Germany the first major carbon adsorption processes were developed. During the 1960s, the magnesium oxide, copper oxide, and sulfite scrubbing processes were investigated.

Lime/limestone processes were installed in 1964 on an iron ore sintering plant in the USSR and on a large sulfuric acid plant in Japan in 1966.

In 1966 Combustion Engineering developed a process which injected dry limestone into the boiler followed by a wet scrubbing operation. In the U.S., the first commercial system of this type was installed in 1968; there were five utility installations of this system by 1972. Because of major problems associated with dry limestone injection, these systems proved inadequate. Problems included plugging (especially of the spaces between boiler tubes), low SO_2 removal, and increased particle emissions from the electrostatic precipitators. The five installations are now either shut down or converted to other types of systems. U.S. lime and limestone FGD technology was substantially improved and advanced via the EPA large pilot facility at TVA's Shawnee Steam Plant. This facility identified scrubber configurations and operating parameters yielding reliable and efficient operation.

FGD has been widely used in Japan and is considered an accomplished technology. Over 1,300 commercial FGD units have been operated to treat gases generated from various processes including many oil-fired boilers. FGD processes treat a total capacity of over 120,000,000 Nm^3/hr (40,000 MW equivalent) to remove 85-90 percent of SO_2. The principal by-products are gypsum, sodium sulfite, and sulfuric acid.

The total capacity of coal-fired utility boilers in Japan is now 4,300 MW (3.7 percent of total utility power) and is expected to reach 10,000 MW (5.6 percent) in 1985 and 22,000 MW (10 percent) in 1990. Several coal-fired industrial boilers also may be constructed in the future. All of these boilers will apply FGD to reduce SO_2 emissions.

Recently, in the United States, dry scrubbing systems employing spray dryers and producing a dry disposable waste are becoming an important part of the U.S. market. Pilot testing and early commercial operation have indicated that such systems can achieve up to 90 percent sulfur control (although most are designed for 70-80 percent control) at costs substantially lower than wet systems for low to moderate sulfur coals.

DESCRIPTION OF FGD SYSTEMS

FGD systems can be classified in two general categories: (1) systems in which the sulfur product generated through a scrubbing or adsorption operation is disposed of as waste (throwaway product systems) and (2) those in which the sulfur product, such as sulfuric acid, is marketed (salable product systems). Although over 50 processes have been tested at bench scale or larger, the number of commercially significant processes is considerably smaller. The following commercially offered throwaway and salable product systems are considered the most important for near-term (through 1990) SO_2 control:

1. Throwaway product systems - lime and limestone scrubbing (both sludge and gypsum variations) and dual (double) alkali.

2. Salable product systems - magnesium oxide scrubbing and Wellman-Lord (sodium sulfite scrubbing).

Other potentially important systems which are close to commercialization include dry scrubbing, seawater scrubbing, carbon adsorption, and copper oxide adsorption. Tables 1, 2, and 3 categorize the important systems as "throwaway;" salable product, gypsum; and salable product, regenerative, respectively, and summarize their commercial status and principles of operation.

A typical lime or limestone wet scrubbing throwaway FGD process associated with a coal-fired utility boiler, shown schematically in Figure 1, illustrates the interrelationships between the various major system components. The major components shown here are: an electrostatic precipitator for upstream dry particle collection, a spray tower absorber (scrubber), a thickener, and filter. There are many variations on this basic scheme.

GROWTH OF U.S. UTILITY APPLICATION

Currently there are 96 FGD units controlling more than 36,000 MW of generating capacity at U.S. utilities. Projecting into the future, there will be a total of 221 units, based on currently operational, under construction, and planned units with relatively firm commitments,

TABLE 1. SUMMARY DESCRIPTION OF FGD PROCESSES - "THROWAWAY" CATEGORY

FGD process (year of first use)	Primary reagent	Product of Disposal	Operating principles	Present status
Limestone/sludge[a] (1933)	$CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with limestone slurry; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Lime/sludge[a] (1972)	CaO	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with slurry of hydrated lime; SO_2 reacts to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Commercial operation (coal and oil), principally in U.S.
Dual (double) alkali/sludge (1974)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	$CaSO_3/CaSO_4$ wet sludge	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and to form insoluble Ca compounds which are separated and partly dewatered for disposal.	Recent commercial operation on coal-fired boilers in U.S.
Seawater scrubbing (1975)	Seawater	Dilute sulfite solution	Flue gases scrubbed with seawater on a once-through system and discharged back to sea.	Commercial small-scale operation on oil-fired boilers in Norway.
Dry scrubbing	CaO or sodium alkali	$CaSO_3$ or Na_2SO_3	Flue gases are treated in a spray dryer where alkali slurry or solution spray absorbs the SO_2, cools the flue gases, and produces a dry waste material collected in a downstream baghouse or electrostatic precipitator.	Several industrial and utility applications in construction and early operational phase currently applicable to coals with low to moderate sulfur content.
Sodium carbonate scrubbing	Na_2CO_3 or other alkali sodium salt	Na_2SO_3/ Na_2SO_4	Flue gases are treated in scrubber with sodium salt solution; spent liquor generally disposed of in evaporation ponds in arid areas.	Commercial in Western U.S. in arid areas where evaporation ponds feasible.

[a]Important variations of these processes are lime/alkaline fly ash and limestone/alkaline fly ash which utilize natural alkalinity in certain coals to greatly minimize reagent requirements.

TABLE 2. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, GYPSUM CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Limestone/gypsum (1973)	$CaCO_3$	Gypsum	Flue gases scrubbed with limestone slurry; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan.
Lime/gypsum (1964)	CaO	Gypsum	Flue gases scrubbed with slurry of hydrated lime; resulting calcium-sulfur compounds are air-oxidized to gypsum, separated, and dewatered.	Commercial operation (coal and oil), principally in Japan, but also recently in West Germany.
Double (dual) alkali/gypsum (1973)	NaOH or Na_2CO_3 and CaO or $CaCO_3$	Gypsum	Flue gases scrubbed with alkaline Na compounds in solution; used solution regenerated with lime or limestone in separate reactor and the insoluble calcium-sulfur compounds then air-oxidized to gypsum, separated, and dewatered.	Commercial operation on oil-fired boilers in Japan.
Dilute sulfuric acid/gypsum (Chiyoda) (1972)	H_2SO_4 and $CaCO_3$	Gypsum	Flue gases are scrubbed with dilute sulfuric acid containing ferric ion catalyst; air oxidation produces more sulfuric acid when bled off and neutralized with limestone; the gypsum is separated and dewatered.	Commercial operation on oil-fired boilers in Japan.

TABLE 3. SUMMARY DESCRIPTION OF FGD PROCESSES - SALABLE PRODUCT, REGENERATIVE CATEGORY

FGD process (year of first use)	Primary reagent	Product of disposal	Operating principles	Present status
Sodium sulfite (Wellman-Lord) (1971)	Na_2CO_3	SO_2	Flue gases are scrubbed with sodium sulfite solution and the resulting sodium bisulfite is thermally regenerated to sodium sulfite and SO_2; the SO_2 is then further treated to marketable products.	Commercial operation on oil-fired boilers in Japan; recent commercial application of coal-fired boilers in U.S.A.; also on chemical/ oil refinery plants.
Magnesium oxide (1972)	MgO	SO_2	Flue gases scrubbed with slurry of hydrated magnesium oxide; insoluble magnesium sulfite is separated and calcined for recycle of MgO and regeneration of SO_2 for further treatment.	Commercial operation on oil-fired boilers in Japan; demonstration plant on coal-fired boiler in U.S.
Carbon absorption (1974)	C	SO_2	SO_2 from flue gases is absorbed on active carbon which is then regenerated thermally, releasing SO_2 for recovery.	Demonstration.
Copper oxide (Shell) (1973)	CuO	SO_2	SO_2 from flue gases is absorbed on copper oxide coated alumina; this is then treated chemically to regenerate the absorber and produce SO_2 for recovery.	Demonstration.

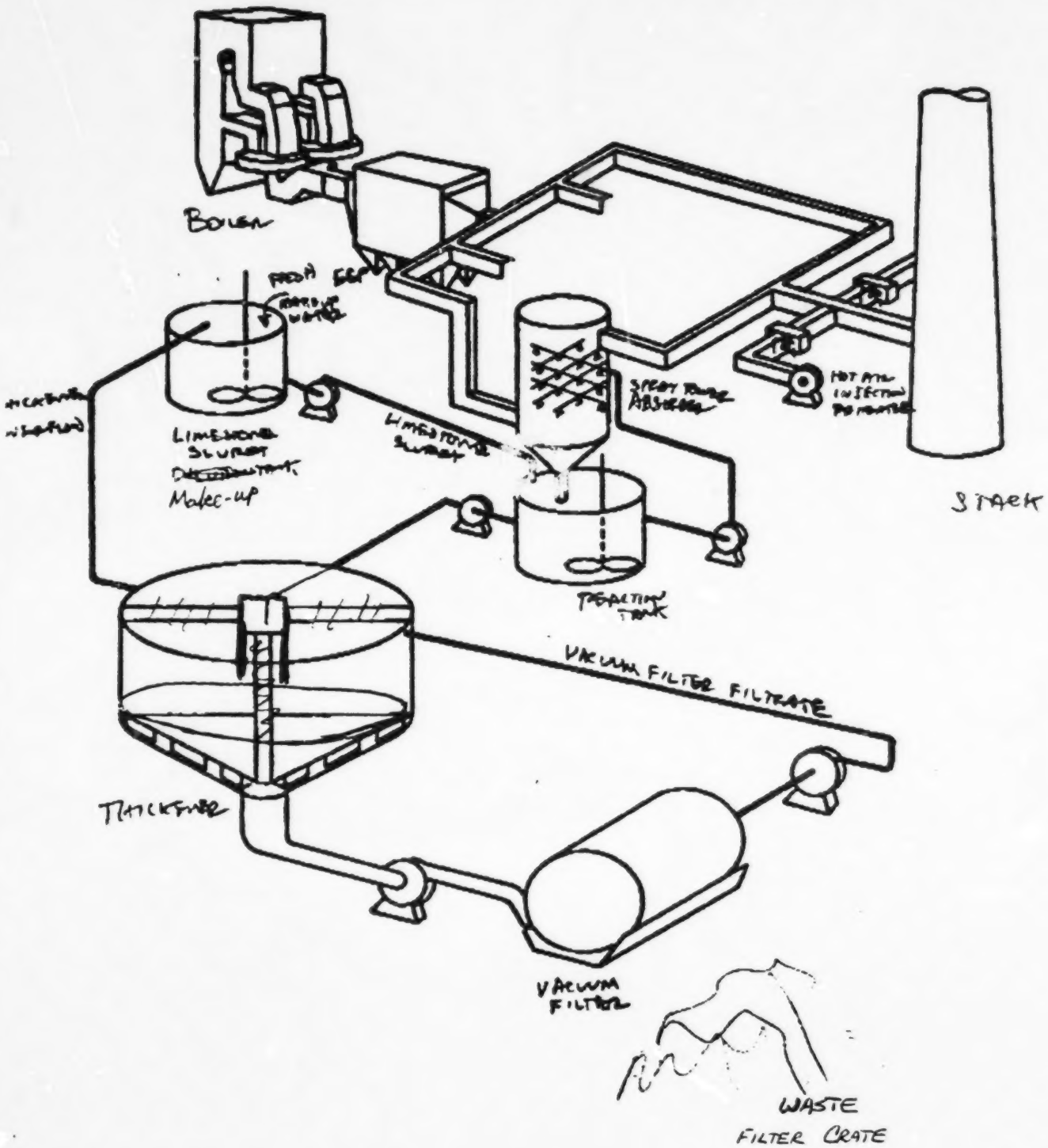


Figure 1. Typical lime or limestone wet scrubbing throwaway FGD process.

to control about 107,000 MW of coal-fired electric generating capacity by the turn of the century. The projected growth of utility FGD application, as a function of the year of the estimate, is shown in Figure 2. Since planned units are based on known commitments, the estimates are conservative. (Capacity is expressed in this paper as Total Controlled Capacity (TCC) or Equivalent Scrubbed Capacity (ESC).)

At the end of 1980 about 40 percent of the nation's electric generating capacity was coal-fired. By the end of the century, the figure is expected to be 45 percent or higher. Currently, about 14 percent of our coal-fired generating capacity is controlled by FGD; by the end of the century, that figure is conservatively estimated to approach 30 percent, with an assumed total growth in generating capacity of 35 percent over the 20-year period.[1]

EPA UTILITY FGD SURVEY

Since 1974, EPA's Industrial Environmental Research Laboratory at Research Triangle Park, North Carolina (IERL-RTP) has employed PEDCo Environmental, Inc. under contract to conduct a data gathering survey of utility FGD systems. PEDCo's function is to gather and systematically tabulate and file design, performance, and cost data on utility FGD systems in operation, under construction, and planned.

Design data include information on the boiler, stack, fans, pumps, tanks, materials of construction, coal composition, removal efficiency, particulate matter control systems, waste disposal, by-product utilization, and other items of interest. Performance data include dependability of the system, problems and solutions, and pollutant removal. Data on real system capital cost and annual revenue requirements are also gathered in the survey, and are presented as "reported" and "adjusted" costs. The "reported" costs are those submitted by the utilities to PEDCo. The "adjusted" costs are the result of an attempt to reduce all utility-reported costs to a relatively comparable basis. The adjustment procedure is described in each update of the EPA Utility FGD Survey.[1]

The information in the survey is supplied voluntarily by utilities, process suppliers and developers, regulatory groups, and others. As such, it is subject to errors in transmission of data or in the lack of uniformity in reporting the data throughout the industry. With these qualifications, it is probably the best comprehensive statistical overview of the status of utility FGD application that exists. Most of the data presented here are taken from the survey.

All of the collected information is stored in a computerized data base called the "Flue Gas Desulfurization Information System" (FGDIS).[2] The FGDIS is accessible to the general public through the National Technical Information Service (NTIS) in Springfield, VA. After obtaining a valid user ID and password, the system can be accessed via a computer terminal and a telephone modem by dialing a local telephone number. The user is charged for the computer time by NTIS.

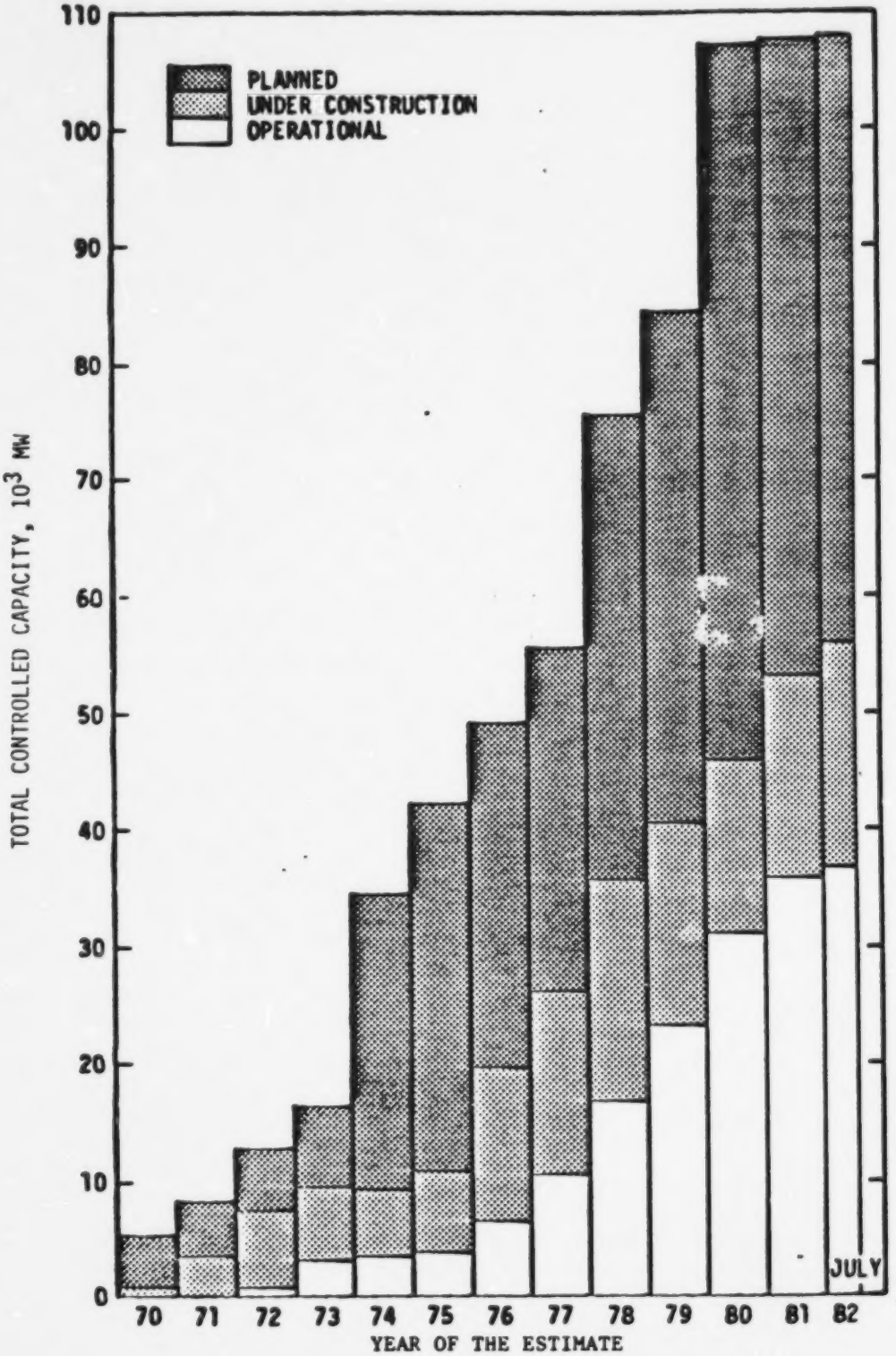


Figure 2. Projected utility FGD capacity.

U.S. TRENDS IN SELECTION OF FGD PROCESSES

The U.S. utility FGD systems are summarized by process type and status category in Table 4, based on FGDIS data.

The vast majority of utility FGD systems in the U.S. are the throwaway variety. Of the presently known, operational, under construction, and planned units, for which a process has been selected, about 95 percent are throwaway and 5 percent are salable product processes. In the operational status, 93 percent are throwaway and 7 percent salable product processes; in the under construction status, 94 percent are throwaway and 6 percent are salable product processes. There are no additional salable product processes in the planned status.[2]

The fact that throwaway systems predominate in utility applications is probably due to more favorable economics and process simplicity. The salable product processes, although more environmentally aesthetic, require much higher capital investment. With current high interest rates, this also translates into higher annual revenue requirements. These facts apparently override the cost savings for waste disposal and by-product credits for the salable product processes in most cases at present. If waste disposal becomes inordinately more expensive, and the value of sulfur products increases significantly, in the future, salable product processes may be more economically favored.

The projected capacity of utility FGD processes in operation at the end of each 2-year period is given by process type in Figure 3. The trend indicated, based on known orders for utility FGD systems, is toward wet limestone throwaway systems with lime throwaway systems maintaining a large market share and dry systems becoming increasingly important.

The trend toward dry systems is indicated in Table 5. Although this is an emerging technology, it is expected that dry systems will be less costly to install and operate than wet systems; however, their application may be limited to low- and medium-sulfur coals if the current NSPS for utility boilers (requiring 70 to 90 percent SO_2 removal or more) is to be achieved. The anticipated and real economic benefits of these systems over the wet systems may diminish as more experience is gained with operating systems; costs for wet systems have increased after operating experience was factored into the design of newer systems.

TABLE 5. COMMITTED FGD CAPACITY - WET VS DRY PROCESSES

	FGD capacity, MW			
	Operational	Under construction	Contract awarded	Total
Wet	32,653	15,849	10,060	58,562
Dry	750	2,893	1,260	4,903
Totals	33,403	18,742	11,320	63,465
% Dry	2	15	11	8

TABLE 4. SUMMARY OF UTIL TY FGD SYSTEMS BY PROCESS AND STATUS CATEGORY

Process	Total		Status category							
			Operational		Under construction		Contract awarded		Planned	
	No.	MW	No.	MW	No.	MW	No.	MW	No.	MW
Aqueous carbonate/spray drying	1	100	1	100	0	0	0	0	0	0
Citrate	1	60	1	60	0	0	0	0	0	0
Lime/gypsum	1	65	0	0	1	65	0	0	0	0
Limestone/gypsum	1	166	0	0	1	166	0	0	0	0
Lime/limestone/gypsum	1	475	0	0	1	475	0	0	0	0
Magnesium oxide	3	724	1	240	2	484	0	0	0	0
Wellman-Lord	7	1,959	7	1,959	0	0	0	0	0	0
Subtotal - Salable product	15	3,549	10	2,359	5	1,190	0	0	0	0
Dual alkali	6	2,288	3	1,181	2	842	1	265	0	0
Lime	32	14,145	24	9,680	5	2,805	1	650	2	1,010
Limestone	81	38,632	38	13,920	19	9,362	14	10,060	10	5,290
Limestone/alkaline fly ash	2	1,500	2	1,500	0	0	0	0	0	0
Lime/alkaline fly ash	11	4,238	9	2,838	2	1,400	0	0	0	0
Lime or limestone (test unit)	2	20	2	20	0	0	0	0	0	0
Lime or sodium carbonate (test unit)	1	100	1	100	0	0	0	0	0	0
Lime/spray drying	13	4,263	1	110	9	2,893	3	1,260	0	0
Process not selected[a]	6	3,530	0	0	0	0	0	0	6	3,530
Sodium carbonate (once through, wet)	9	3,155	5	1,255	1	250	0	0	3	1,650
Sodium carbonate/spray drying	1	440	1	440	0	0	0	0	0	0
Subtotal - Throwaway product	164	72,311	86	31,044	38	17,552	19	12,235	21	11,480
Totals	179	75,860	96	33,403	43	18,742	19	12,235	21	11,480
Salable product process % of total MW		5		7		6		0		0

[a] A process has not been selected for these throwaway product FGD systems. An additional 42 units are undecided (with respect to salable or throwaway product) and are not included in this table.

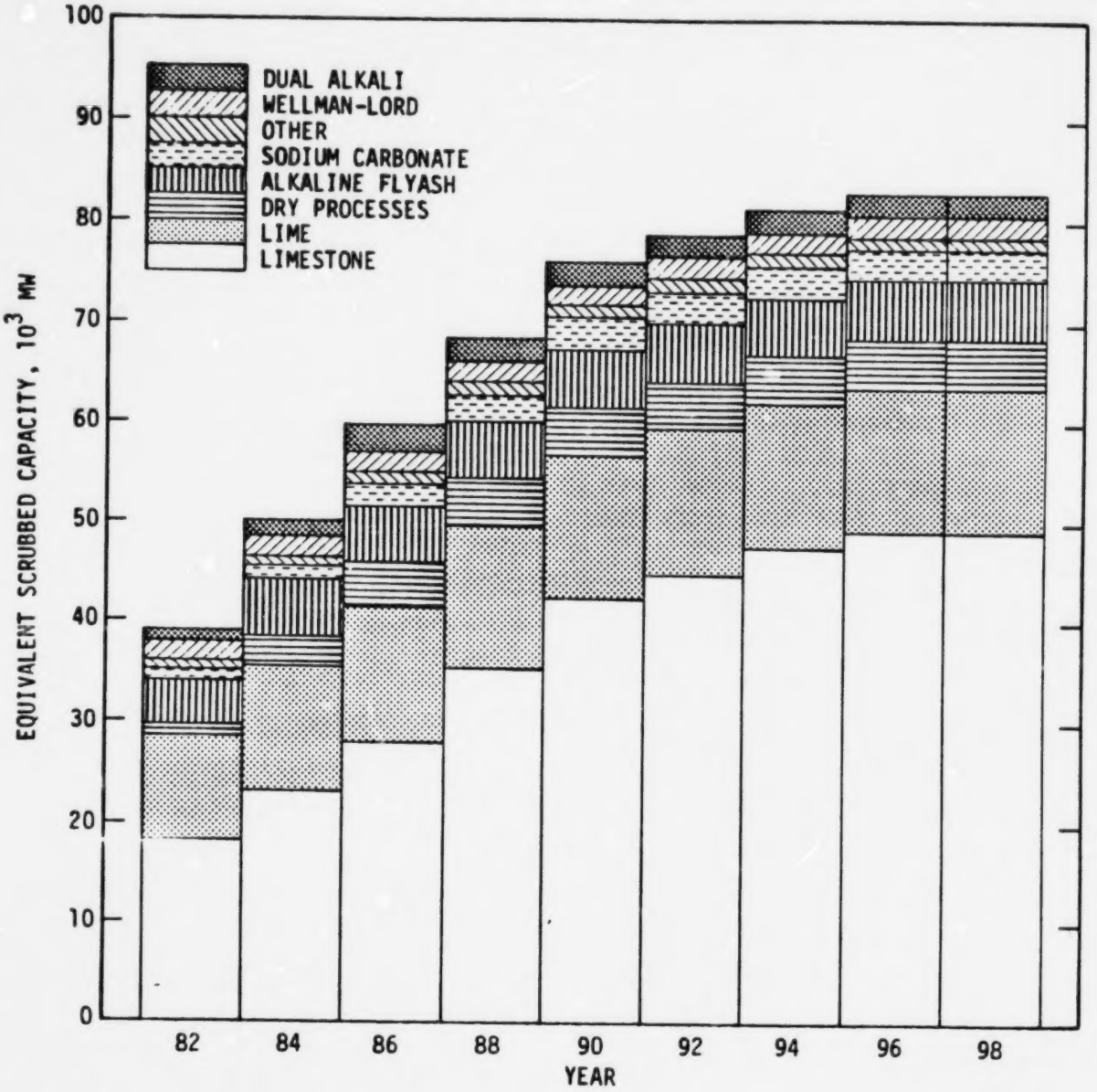


Figure 3. Projected utility FGD capacity (where process has been selected).

ENERGY CONSUMPTION

One frequently cited disadvantage of an FGD system is that it reduces the output of energy produced by a power plant. Although this is a fact, the energy consumption has been frequently overstated.

Values of energy consumption for some of the operational utility FGD systems are tabulated in Table 6 from the FGDIS data base.

TABLE 6. ENERGY CONSUMPTION FOR OPERATIONAL FGD SYSTEMS[a,b]

Process	Range	Average
Dual alkali	0.8 - 2.4	1.4
Lime	1.3 - 4.1	2.3
Limestone	0.9 - 5.2	2.7
Sodium carbonate (once-through, wet)	0.2 - 1.5	0.8
Wellman-Lord	3.6 - 4.6	4.0

[a]Excluding flue gas reheat.

[b]Electrical energy consumption of the FGD installation as a percentage of gross unit generating capacity.

Generally, the regenerable salable product systems require substantially more input energy for the regeneration step.

WASTE DISPOSAL

An area of great interest in the throwaway systems is the waste disposal method. Typical sludge from a wet FGD system is a mixture of calcium sulfite and sulfate containing a certain amount of fly ash and about 50 percent by weight of free water. Without stabilization it might have a consistency comparable to wet clay or toothpaste.

Disposal is generally by ponding or landfilling. Ponds may be lined with a clay bottom, a polymer or rubberized sheet bottom (although this is very costly and generally not used), or unlined. Lining prevents percolation into the groundwater of occluded sludge liquors containing a vast variety of chemical constituents found in the fly ash or generated by reactions in the FGD system. Sludge is generally sluiced to the pond, the waste solids settle, and supernate pond water is returned to the FGD system for reuse. Landfilling is generally accomplished by trucking or otherwise transporting the waste to a landfill site after some form of treatment.

Treatment may include forced oxidation, fixation, and/or stabilization. Forced oxidation involves reacting the calcium sulfite/sulfate mixture with oxygen from the air as a separate step in the FGD process. This converts most of the waste to gypsum which can be dewatered to 80-90 percent solids using thickeners, filters, and/or centrifuges, so that the waste is mechanically stable for landfill. Stabilization might involve mixing dry fly ash with the wet sludge to produce a more mechanically stable landfill. The quantities of FGD waste (dry basis) and fly ash in the mixture are generally of the same order of magnitude. Fixation generally means achieving mechanical stability through pozzolanic chemical reaction. Again the wet solids might be mixed with an equal amount of dry fly ash and about 3-5 percent by weight of lime. This mixture then undergoes pozzolanic reactions that make the waste more mechanically stable and less permeable to rainwater, thus locking in many of the soluble constituents of the sludge liquor. Permeability is further reduced by mechanical compaction at the disposal site. Another fixation process that has been used involves mixing fly ash and other fixation chemicals with the FGD wastes and sluicing the mixture to a pond. The mixture of solids then settles to the bottom of the pond and undergoes pozzolanic reactions (sets up) underwater. Several companies offer sludge fixation and stabilization processes. Disposal characteristics for the utility systems currently operational and under construction are given in Table 7.

TABLE 7. DISPOSAL CHARACTERISTICS OF UTILITY FGD SYSTEMS

Disposal characteristics	Operational		Under construction	
	No.	MW	No.	MW
Sludge processing type				
Untreated	24	6,495	4	1,922
Treated				
Forced oxidation	14	7,078	7	3,890
Fixation	19	9,314	7	3,004
Stabilization	16	6,036	4	2,017
Sludge disposal method				
Landfill	39	13,597	24	9,557
Pond	48	17,291	7	3,082

The table shows a trend toward landfill vs ponding for the units scheduled for future operation, judging by a comparison of the currently operational and under construction units. No definite treatment trend is indicated in the type of treatment used. Treatment method (or the lack of it) is dictated by site-specific economic and local regulatory or permitting requirements.

PARTICULATE MATTER CONTROL

Particulate matter control must be considered along with the installation of a utility FGD system. The three methods currently considered are:

- Electrostatic Precipitator (ESP).
- Fabric Filter (FF).
- Wet Scrubbing.

Dry collection of fly ash upstream of a wet FGD system may be desirable since dry fly ash may be needed to fix or stabilize the waste. Collecting fly ash in a wet scrubbing process can create wet/dry interface scaling and fouling problems due to pozzolanic reaction with calcium compounds in the scrubber. In addition, fly ash tends to be very erosive in wet scrubbing systems, thus causing more maintenance problems.

On the other hand, fly ash may contain alkaline compounds such as CaO, MgO, and Na_2O which assist in SO_2 removal, thus giving rise to design for wet scrubbing of particulate matter in conjunction with SO_2 removal. When wet scrubbing is employed, the design usually involves a two-stage scrubbing system in which particulate matter is removed in the first stage and SO_2 is removed primarily in the second stage. To remove a large fraction of particulate matter, especially the finer particles, a high gas pressure drop is required, and thus an energy penalty results due to higher fan energy requirements. The methods used and planned for future use in utility FGD are tabulated in Table 8. A clear preference for ESPs is shown. Wet scrubbing for particle control, although significant in the currently operational units, shows a clear decline in preference based on known plans for future units (the NSPS requires more stringent control than can reasonably be achieved by wet scrubbing alone).

TABLE 8. SUMMARY OF PARTICLE EMISSION CONTROL SELECTION

	Operational		Under construction		Planned units	
	No.	MW	No.	MW	No.	MW
Electrostatic precipitator	60	21,823	26	11,731	25	16,580
Fabric filter	3	650	11	3,458	11	5,228
Wet scrubbing	23	7,371	3	1,650	0	0
Electrostatic precipitator and wet scrubbing	10	3,559	3	1,903	0	0
Total	96	33,403	43	18,742	36	21,808

DEPENDABILITY

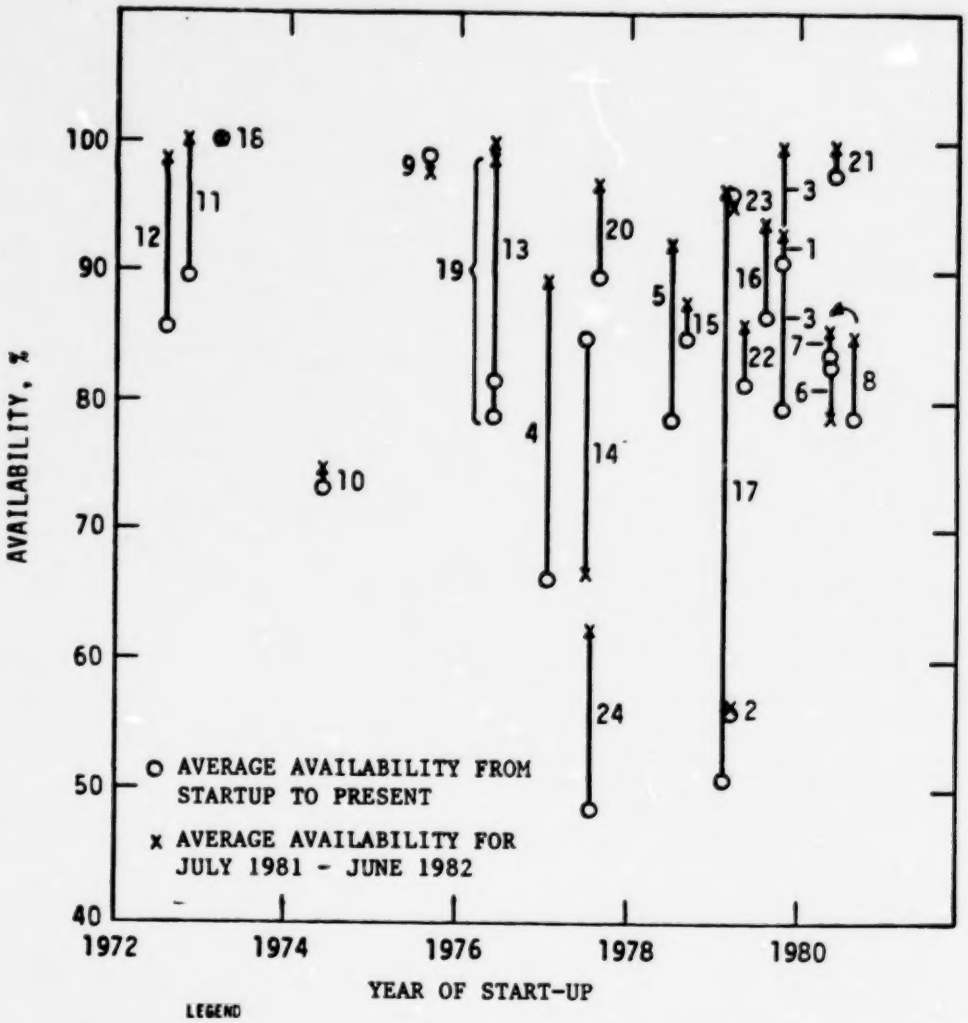
During the past decade, as the number of utility FCD systems has increased dramatically, we have monitored their dependability via the Utility FGD Survey and FGDIS.

There are many ways to measure and express a unit's dependability. None of them provides a completely precise measure. The FGDIS uses four indices[1,2] to characterize dependability. For this paper we have selected to utilize availability as a measure of dependability. Availability is defined as the hours the FGD system is available for operation (whether operated or not) divided by hours in the period, expressed as a percentage. This parameter can, in some cases, overestimate the viability of the FGD system since, during periods in which it is decided not to use the FGD system and during boiler downtime, this definition assumes the FGD unit is available even though it could have developed problems during such periods. Three other parameters frequently used, operability, reliability, and utilization, are defined in the EPA Utility FGD Survey.[1]

The average availabilities from start-up to the present, and for the latest 12-month period, are plotted against the year in which the unit was started up for both high- and low-sulfur coal units in Figures 4 and 5, respectively. High-sulfur coal was arbitrarily defined as having greater than 2 percent sulfur by weight. Only commercial (non-test units) required to achieve a minimum of 520 ng/J (1.2 lb/10^6 Btu), SO_2 emissions, and which had at least 2 years of operation, were plotted, using data from the FGDIS.

In the vast majority of the units plotted, the average availability was higher during the latest 12-month period than during the whole period of operation. As might be expected, availability improves after a period of shakedown or "debugging" and the operators gain experience in operating the system; at least, that's our interpretation of the data. In addition, it appears that most of the availability figures for the latest 12-month period are in the 80 to 100 percent range.

Using the FGDIS, a categorical tabulation of domestic utility FGD system dependability by process was developed and is presented in Table 9. The table presents the number of operating FGD systems, number currently reporting availability, and average availability for the last 12-month period by process, FGD system age, application (new vs retrofit), and coal sulfur content. The table shows that, except for the citrate process which is in an early stage of commercial development, most of the "second generation" FGD processes have better availability performance than the lime and limestone throwaway processes which are the mainstays of the industry; however, in perspective, there are much more data and experience with the lime and limestone processes. As indicated previously, the trend toward increasing availability with age of the system is evident. There appears to be no clear trend with respect to availability



LEGEND

Big Rivers Electric
(1) Green 1, Lime, 242 MW ESC

Central Illinois Light
(2) Duck Creek 1, Limestone, 416 MW ESC

Central Illinois Public Service
(3) Newton 1, Dual Alkali, 617 MW ESC

Columbus & Southern Ohio Electric
(4) Conesville 5, Lime, 411 MW ESC
(5) Conesville 6, Lime, 411 MW ESC

Delmarva Power & Light
(6) Delaware City 1, Wellman Lord, 60 MW ESC
(7) Delaware City 2, Wellman Lord, 60 MW ESC
(8) Delaware City 3, Wellman Lord, 60 MW ESC

Duquesne Light
(9) Elrama 1-4, Lime, 510 MW ESC
(10) Phillips 1-6, Lime, 408 MW ESC

Kansas City Power & Light
(11) Hawthorn 3, Lime, 90 MW ESC
(12) Hawthorn 4, Lime, 90 MW ESC

Kentucky Utilities
(13) Green River 1-3, Lime, 64 MW ESC

Louisville Gas & Electric
(14) Cane Run 4, Lime, 188 MW ESC
(15) Cane Run 5, Lime, 200 MW ESC
(16) Cane Run 6, Dual Alkali, 299 MW ESC
(17) Mill Creek 3, Lime, 427 MW ESC
(18) Paddy's Run 6 , Lime, 72 MW ESC

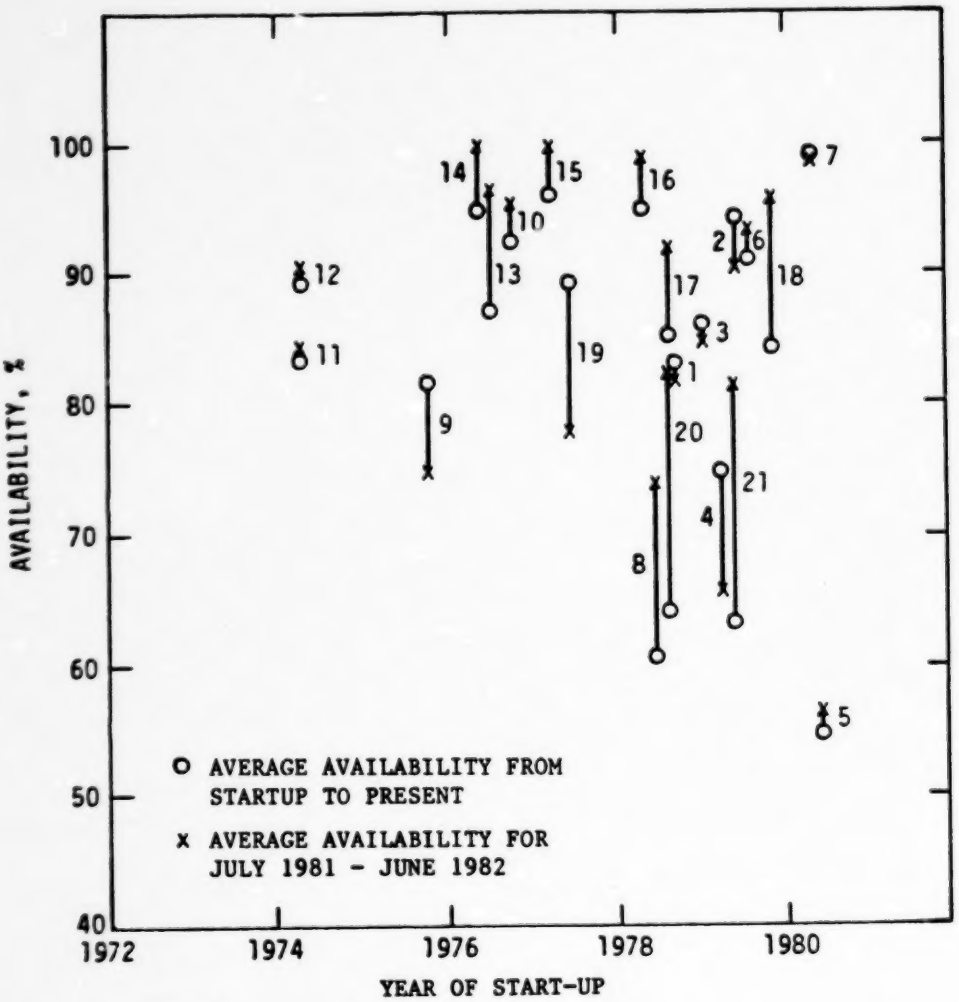
Pennsylvania Power
(19) Bruce Mansfield 1, Lime, 917 MW ESC
(20) Bruce Mansfield 2, Lime, 917 MW ESC
(21) Bruce Mansfield 3, Lime, 917 MW ESC

Southern Illinois Power
(22) Marion 4, Limestone, 184 MW ESC

Southern Indiana Gas & Electric
(23) A.B. Brown 1, Dual Alkali, 265 MW ESC

Springfield City Utilities
(24) Southwest 1, Limestone, 194 MW ESC

Figure 4. Availability for high-sulfur coal utility FGD units.



LEGEND

Alabama Electric
(1) Tombigbee 2, Limestone, 179MW ESC
(2) Tombigbee 3, Limestone, 179MW ESC

Arizona Electric Power
(3) Apache 2, Limestone, 98 MW ESC
(4) Apache 3, Limestone, 98 MW ESC

Colorado Ute Electric
(5) Craig 2, Limestone, 410 MW ESC

Cooperative Power Association
(6) Coal Creek 1, Lime/Alkaline Flyash, 327 MW ESC

Minnesota Power & Light
(7) Clay Boswell 4, Lime/Alkaline Flyash, 475 MW ESC

Minnkota Power
(8) Milton R. Young B, Lime/Alkaline Flyash, 374 MW ESC

Montana Power
(9) Colstrip 1, Lime/Alkaline Flyash, 360 MW ESC
(10) Colstrip 2, Lime/Alkaline Flyash, 360 MW ESC

Nevada Power
(11) Reid Gardner 1, Sodium Carbonate, 125 MW ESC
(12) Reid Gardner 2, Sodium Carbonate, 125 MW ESC
(13) Reid Gardner 3, Sodium Carbonate, 125 MW ESC

Northern States Power
(14) Sherburne 1, Limestone/Alkaline Flyash, 740 MW ESC
(15) Sherburne 2, Limestone/Alkaline Flyash, 740 MW ESC

Public Service of New Mexico
(16) San Juan 1, Wellman Lord, 361 MW ESC
(17) San Juan 2, Wellman Lord, 350 MW ESC
(18) San Juan 3, Wellman Lord, 534 MW ESC

South Carolina Public Service
(19) Winyah 2, Limestone, 140 MW ESC

South Mississippi Electric Power
(20) R.D. Morrow, Sr. 1, Limestone, 124 MW ESC
(21) R.D. Morrow, Sr. 2, Limestone, 124 MW ESC

Figure 5. Availability for low-sulfur coal utility FGD units.

TABLE 9. CATEGORICAL SUMMARY OF DOMESTIC FGD SYSTEM AVAILABILITIES

Category	No. of operating FGD systems	No. of FGD systems currently reporting availability	Average availability for July 1981 - June 1982
Process			
Limestone/alkaline fly ash	2	2	100.00
Dual alkali	3	3	96.92
Sodium carbonate	5	4	90.49
Wellman Lord	7	7	89.14
Lime/alkaline fly ash	9	6	86.85
Lime	24	23	84.14
Limestone	38	24	75.56
Citrate	1	1	14.90
FGD system age			
0 through 2 years	26	12	80.38
Greater than 2 years through 4 years	33	28	80.47
Greater than 4 years	37	30	86.96
Application			
New	62	47	82.38
Retrofit	34	23	82.22
Coal sulfur content			
Low (<1.0% S)	45	32	86.15
Medium (1.0 to 3.0% S)	24	14	77.31
High (>3.0% S)	30	27	81.04

vs new or retrofit application. Availability appears to be better for low-sulfur coal units than for medium- or high-sulfur coal units. In the past, FGD critics frequently stated that high availability was hard to achieve with high-sulfur coal. These data show, however, that availabilities for high-sulfur coal units are now intermediate between low- and medium-sulfur coal unit availabilities. We speculate that some of this may be due to the high availabilities achieved by dual alkali systems in high sulfur coal applications, and to the general increase of availability with age of the system (this assumes more of the high-sulfur coal units are older).

FGD COSTS

The subject of FGD costs has generated much confusion and controversy. This is understandable when one considers the variety of processes, coal types, and site specific conditions, as well as the differences and inaccuracies in various cost estimating techniques.

Costs are generally categorized as capital costs and annual revenue requirements. The former include: direct investment, indirect investment, land costs, working capital, contingency, and other capital charges including interest during construction and allowance for start-up and modifications. The latter include: direct costs for raw materials, labor, supervision, utilities, and maintenance; and indirect costs for capital charges and overheads. The annual revenue requirements figure is representative of the cost to the consumer and is expressed as a unit cost of electrical energy (e.g., mills/kWh). The capital cost is more a concern of the utility industry particularly when interest rates are high, in that it represents a capital expenditure which must be paid for with revenues raised through the sale of stocks or bonds or other means of capitalization.

Two basic approaches to estimating costs for FGD systems are:

1. Gathering data on actual FGD systems and making adjustments to express these on a relatively common basis.

2. Establishing a set of design and economic premises and arriving at a cost estimate through the use of an appropriate engineering/economic mathematical model, to design the system.

We have used both approaches to arrive at categorical utility FGD capital costs and annual revenue requirements. The first approach has been used by PEDCo Environmental, Inc. in the EPA Utility FGD Survey[1] and in the FGDIS.[2] The second approach has been used by TVA in several cost analysis projects under an interagency agreement with EPA. Since the actual systems were installed under conditions that never exactly fit the TVA design and economic premises, and several systems had certain unique site specific circumstances, one would not expect perfect agreement between the two approaches; however, the authors believe agreement within about 30 percent would be considered good considering the limitations of the systems.

Adjusted Actual Costs

In the first approach PEDCo has adjusted the costs of all operational utility FGD systems, for which the respective utility companies have reported data, to a common basis using a cost adjustment procedure that focuses on the following items:

- All capital costs are adjusted to mid-1981 dollars using appropriate escalation factors.
- Gross unit capacity is used to express all FGD capital expenditures because the capital requirement of an FGD system is dependent on actual boiler size before derating for auxiliary and air quality control power requirements.
- Particulate matter control costs are deducted.
- The capital costs associated with the modification, or installation of equipment not part of the FGD system but needed for its proper functioning, are included (e.g., stack lining, modification to existing ductwork or fans).
- Indirect charges are adjusted to provide adequate funds for engineering, field expenses, legal expenses, insurance, interest during construction, allowance for start-up, taxes, and contingency expenditures.
- All annual revenue requirements, represented in mills/kilowatt-hour (mills/kWh), are expressed in terms of net megawatts (MW).
- Net unit capacity is used to express all FGD annual revenue requirements.
- All non-labor annual revenue requirements are adjusted to a common 65 percent capacity factor.
- Replacement power costs for retrofitted FGD systems are not included since only a few utilities reported such costs and these were presented using a variety of methods.
- Sludge disposal costs are adjusted to reflect the costs of sulfur dioxide waste disposal only (i.e., excluding fly ash disposal except where usable as a sludge stabilizing agent) and to provide for disposal over the anticipated lifetime of the FGD system.

- A 30-year life is assumed for all process and economic considerations for all new systems that were installed for the life of the unit. A 20-year life is assumed for all process and economic considerations for retrofit systems that were installed for the remaining portion of the life of the unit.

- Regeneration and by-product recovery facility costs are added for those regenerable systems not reporting such costs.

A tabulation of the adjusted capital costs and annual revenue requirements for the operational utility FGD systems in the FGDIS data base is given in Table 10.

A categorical summary of these results, including a range and average cost regardless of the unit's capacity or coal sulfur content, is given in Table 11.

Design Model Costs

In one example of the design model approach to FGD cost estimating, TVA has estimated the cost for nine FGD processes in the "NATO-CCMS Flue Gas Desulfurization Pilot Study.[3] The basis of the economic evaluation is an FGD system for a new midwestern U.S. 500 MW power plant. The FGD system is designed for removal of 90 percent of the SO_2 in the flue gas Six fuels consisting of bituminous coal, lignite, and oil were evaluated. Scaling procedures were utilized for projection of costs for other conditions such as different power plant size and coal sulfur content. Models were utilized for nine flue gas desulfurization processes deemed to be important on a world-wide basis. The design FGD process is assumed to have a 30-year lifetime of 117,500 operating hours and to operate 6,000 hours in the first year. Fly ash removal by electrostatic precipitator upstream of the FGD system is not included in the FGD cost.

The economic premises are based on U.S. regulated utility economics and financing. The cost estimates consist of capital costs for construction of the FGD system and annual revenue requirements for the first year of operation. The capital costs consist of all direct and indirect costs for equipment, land, materials, labor, fees, services, and other construction costs required to install the FGD system. Annual revenue requirements consist of all raw material, labor, utility, and other conversion costs and indirect costs such as capital charges, taxes, and overheads. By-product sales for processes producing elemental sulfur, sulfuric acid, gypsum, and sodium sulfate are included as credits. The technical design premises for the nine processes are summarized in Table 12.

Process and economic evaluation results are shown for a variety of size and fuel variations in Table 13. Accuracy ranges for the 500 MW base case investment and annual revenue requirements are shown in Figures 6 and 7. All capital investments are mid-1979 U.S. dollars; all revenue requirements are mid-1980 U.S. dollars.

TABLE 10. ADJUSTED CAPI AL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Alabama Electric					
Tombigbee 2	Limestone	1.61	179	38.30	3.18
Tombigbee 3	Limestone	1.61	179	38.30	3.18
Arizona Electric Power					
Apache 2	Limestone	0.50	98	67.50	3.75
Apache 3	Limestone	0.50	98	59.80	3.75
Arizona Public Service					
Cholla 1	Limestone	0.50	119	81.30	4.79
Cholla 2	Limestone	0.50	285	162.10	8.22
Central Illinois Light					
Duck Creek 1	Lime	3.40	416	132.20	5.78
Central Illinois Public Service					
Newton 1	Dual alkali	3.00	617	263.90	13.94
Colorado Ute Electric					
Craig 1	Limestone	0.45	410	105.90	5.33
Craig 2	Limestone	0.45	410	90.30	4.56
Columbus & Southern Ohio Electric					
Conesville 5	Lime	4.67	411	99.40	6.78
Conesville 6	Lime	4.67	411	99.40	6.78
Cooperative Power Association					
Coal Creek 1	Lime/alkaline fly ash	0.63	327	52.50	2.99
Coal Creek 2	Lime/alkaline fly ash	0.63	327	52.50	2.99

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Duquesne Light					
Elrama 1-4	Lime	2.05	510	187.80	12.89
Phillips 1-6	Lime	2.05	408	210.00	17.65
Indianapolis Power & Light					
Petersburg 3	Limestone	3.25	532	162.10	9.74
Kansas City Power & Light					
Hawthorne 3	Lime	2.05	90	62.80	5.25
Hawthorne 4	Lime	2.05	90	62.80	5.25
La Cygne 1	Lime/alkaline limestone	5.39	874	100.10	11.29
Kansas Power & Light					
Jeffrey 1	Limestone	0.32	540	55.90	2.42
Jeffrey 2	Limestone	0.30	490	41.20	1.65
Kentucky Utilities					
Green River 1-3	Lime	2.50	64	117.80	10.99
Louisville Gas & Electric					
Cane Run 4	Lime	3.75	188	115.20	6.20
Cane Run 5	Lime	3.75	200	102.40	5.30
Cane Run 6	Dual alkali	4.80	299	87.80	7.23
Mill Creek 1	Lime	3.75	358	60.40	4.26
Mill Creek 3	Lime	3.87	427	66.00	4.03
Paddy's Run 6	Lime	3.70	72	133.00	12.25
Minnesota Power and Light					
Clay Boswell 4	Lime/alkaline fly ash	0.94	475	184.40	14.09

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Minnkota Power					
Milton R. Young 2	Lime/alkaline fly ash	0.60	374	155.70	6.44
Monongahela Power					
Pleasants 1	Lime	3.00	626	152.90	7.94
Pleasants 2	Lime	3.00	626	152.90	7.94
Montana Power					
Colstrip 1	Lime/alkaline fly ash	0.78	360	145.90	8.27
Colstrip 2	Lime/alkaline fly ash	0.78	360	145.90	8.27
Nevada Power					
Reid Gardner 1	Sodium carbonate	0.50	125	87.10	5.78
Reid Gardner 2	Sodium carbonate	0.50	125	87.10	5.78
Reid Gardner 3	Sodium carbonate	0.50	125	150.90	7.40
Northern States Power					
Sherburne 1	Limestone/alkaline fly ash	0.80	740	102.60	5.43
Sherburne 2	Limestone/alkaline fly ash	0.80	740	102.60	5.43
Pacific Power and Light					
Jim Bridger 4	Sodium carbonate	0.56	550	118.40	6.81
Pennsylvania Power					
Bruce Mansfield 1	Lime	3.00	917	144.20	11.31
Bruce Mansfield 2	Lime	3.00	917	144.20	11.31
Bruce Mansfield 3	Lime	3.00	917	181.10	10.27

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Public Service of New Mexico					
San Juan 1	Wellman-Lord	0.80	361	277.90	16.69
San Juan 2	Wellman-Lord	0.80	350	282.20	16.89
Salt River Project					
Coronado 1	Limestone	0.55	320	86.50	7.70
Coronado 2	Limestone	0.55	320	86.50	7.70
South Carolina Public Service					
Winyah 2	Limestone	1.00	140	47.00	1.84
Winyah 3	Limestone	1.00	280	66.60	4.83
Southern Mississippi Electric Power					
R. D. Morrow 1	Limestone	1.64	124	118.50	6.94
R. D. Morrow 2	Limestone	1.64	124	118.50	6.94
Southern Illinois Power					
Marion 4	Limestone	3.75	184	120.80	7.75
Southern Indiana Gas and Electric					
A. B. Brown 1	Dual alkali	3.35	265	88.40	4.98
Springfield City Utilities					
Southwest 1	Limestone	3.50	194	143.40	8.21
Springfield Water, Light & Power					
Dallman 3	Limestone	3.30	205	194.30	14.56
Tennessee Valley Authority					
Widows Creek 8	Limestone	3.70	550	158.10	7.28

(continued)

TABLE 10. ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FROM THE FGDIS (Continued)

Utility/unit	Process type	Coal sulfur content, %	Equivalent scrubbed capacity, MW	Adjusted capital cost,[a] $/kW	Adjusted annual cost,[a] mills/kWh
Utah Power & Light					
Hunter 1	Lime	0.55	360	75.10	4.66
Hunter 2	Lime	0.55	360	72.60	4.55
Huntington 1	Lime	0.55	366	90.00	5.89

[a] The adjusted capital and annual costs are taken from the Flue Gas Desulfurization Information System (FGDIS). The costs are adjusted to common 1981 dollars.

TABLE 11. CATEGORICAL SUMMARY OF THE ADJUSTED CAPITAL COSTS AND ANNUAL REVENUE REQUIREMENTS FOR OPERATIONAL FGD SYSTEMS

Category	Capital		Annual	
	Range, $/kW	Average, $/kW	Range, mills/kWh	Average, mills/kWh
All	38.3-282.2	118.8	1.6-20.8	7.6
New	38.3-263.9	110.8	1.6-14.6	6.8
Retrofit	60.4-282.2	139.3	4.3-20.8	9.7
Salable	254.6-282.2	271.6	16.7-20.8	18.1
Throwaway	38.3-263.9	110.9	1.6-17.6	7.0
Process				
Limestone	38.3-194.3	98.9	1.6-14.6	6.1
Lime	60.4-210.0	116.5	4.0-17.6	8.1
Dual alkali	87.8-263.9	146.7	5.0-13.9	8.7
Lime/alkaline fly ash	52.5-184.4	122.8	3.0-14.1	7.2
Sodium carbonate	87.1-150.9	110.9	5.8-7.4	6.4
Wellman-Lord	254.6-282.2	271.6	16.7-20.8	18.1
Limestone/ alkaline fly	102.6-102.6	102.6	5.4-5.4	5.4

TABLE 12. SUMMARY - BASE-CASE FGD DESIGN ASSUMPTIONS

Design factor	FGD processes			
	Limestone sludge	Lime sludge	Double-alkali sludge	Seawater[a]
SO_2 removal device	Mobile bed	Mobile bed	Tray tower	Packed bed
Stoichiometry, mol/mol SO_2 removal	1.4	1.05	1.0	-
Design gas velocity, m/sec (SO_2 removal device)	3.8	3.8	2.1	1.8
L/G, liters/m^3				
Presaturator	0.6	0.5	0.5	0.5
Chloride scrubber	-	-	-	-
SO_2 removal device	6.7	7.4	0.9	8.0
Design pressure drop, kPascals (SO_2 removal device)	2.14	2.14	1.25	1.05
Reheat temperature, °C	79	79	79	79
Byproduct/waste management	Clay-lined disposal pond	Clay-lined disposal pond	Clay-lined disposal pond	Returned to sea
Probable accuracy range factors for capital investment estimates	0.85 to 1.20	0.85 to 1.20	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel variations 200 MW 500 MW 1000 MW	5 fuel variations	5 fuel variations	3 fuel variations low reheat

(continued)

TABLE 12. SUMMARY - BASE-CASE FGD DESIGN ASSUMPTIONS (Continued)

Design factor	FGD processes				
	Lime gypsum	Jet-bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption
SO_2 removal device	ROTOPART gas scrubber-separator	Jet-bubbling reactor	Spray grid tower	Valve tray	Moving bed
Stoichiometry, mol/mol SO_2 removal	1.01	1.0	1.05	1.0	7.5 kg $/100 kg char
Design gas velocity, m/sec (SO_2 removal device)	12.2	Proprietary	3.8	-	-
L/G, liters/m^3					
Presaturator	-	Proprietary	-	-	-
Chloride scrubber	-	-	0.5	1.6	-
SO_2 removal device	-	Proprietary	3.0	-	-
Design pressure drop, kPascals (SO_2 removal device)	2.44	3.94	3.24	2.64	0.5 first stage 0.3 second stage
Reheat temperature, °C	79	79	79	79	None
Byproduct/waste management (sales credit, $/short ton)	Gypsum 3.00/ton	Gypsum 3.00/ton	sulfuric acid 25.00/ton 100% acid	sulfuric acid 25.00/ton 100% acid	Sulfur 40.00/ short ton
Probable accuracy range factors for capital investment estimates	0.70 to 1.50	0.70 to 1.50	0.80 to 1.30	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel variations	5 fuel variations	5 fuel variations	5 fuel variations sulfur production	5 fuel variations

Basis for all base-case processes:
99.2% fly ash removed in ESP and disposed of separately, 95% of S in coal emitted in flue gas, 90% FGD SO_x removal, 4 absorber trains with reheat to 79°C for all wet processes, 2 adsorber trains and no reheat for the carbon adsorption process, 3.5% S (5,830 kcal/kg) coal.

[a]Seawater base-case fuel is 1.4% S coal.

[b]Case variation fuels, 0.8% S (5,280 kcal/kg), 1.4% S (7,000 kcal/kg), and 2.0% S (6,110 kcal/kg) bituminous coal; 0.5% S (4,390 kcal/kg) lignite and 2.5% S (10,490 kcal/kg) oil. 3.5% S and 2.0% S coal not used in seawater process.

TABLE 13. SUMMARIZED RESULTS - ENERGY, LAND, CAPITAL INVESTMENT, AND ANNUAL REVENUE REQUIREMENTS

Process	Energy consumption, % of input energy	Land hectares	Capital investment		Annual revenue requirements	
			10^6 $	$/kW	10^6 $	mills/kWh
Limestone sludge						
0.8% S in coal	3.3	42	40.0	80	11.2	3.7
1.4% S in coal	3.2	56	41.6	83	11.5	3.9
2.0% S in coal	3.2	78	45.5	91	12.6	4.2
3.5% S in coal	3.3	127	53.1	106	14.6	4.9
0.5% S in lignite	3.3	34	39.0	78	10.9	3.7
2.5% S in oil	2.7	70	40.6	81	11.4	3.8
200 MW, 3.5% S in coal	3.4	64	26.3	132	7.0	5.9
700 MW, 3.5% S in coal	3.3	163	71.0	101	19.7	4.7
1000 MW, 3.5% S in coal	3.3	213	93.9	94	26.4	4.4
Lime sludge						
0.8% S in coal	3.3	35	37.8	76	11.1	3.7
1.4% S in coal	3.1	47	38.9	78	11.5	3.8
2.0% S in coal	3.2	66	42.0	84	12.6	4.2
3.5% S in coal	3.2	107	47.7	96	15.0	5.0
0.5% S in lignite	3.3	28	37.2	74	10.8	3.6
2.5% S in oil	2.5	57	37.3	75	11.4	3.8
Dual (double) alkali sludge						
0.8% S in coal	2.5	38	40.5	81	11.2	3.7
1.4% S in coal	2.4	49	42.2	84	11.8	3.9
2.0% S in coal	2.5	67	46.0	92	13.1	4.4
3.5% S in coal	2.5	104	53.2	107	16.0	5.3
0.5% S in lignite	2.5	36	39.6	79	10.8	3.6
2.5% S in oil	1.9	53	40.7	81	11.9	4.0
Seawater						
0.8% S in coal	4.2	2	29.6	59	8.7	2.9
1.4% S in coal	4.2	2	30.0	60	8.7	2.9
0.5% S in lignite	4.2	2	29.1	58	8.5	2.8
2.5% S in oil	3.5	2	27.9	56	8.6	2.9
1.4% S in coal, low reheat	2.8	2	28.6	57	7.8	2.6
Lime gypsum						
0.8% S in coal	2.9	5	35.5	71	9.8	3.3
1.4% S in coal	2.9	5	36.5	73	10.3	3.4
2.0% S in coal	3.2	5	39.2	78	11.4	3.8
3.5% S in coal	3.7	5	44.0	88	13.7	4.6
0.5% S in lignite	2.9	5	34.9	70	9.6	3.2
2.5% S in oil	2.5	5	34.8	70	10.3	3.5

(continued)

TABLE 13. SUMMARIZED RESULTS - ENERGY, LAND, CAPITAL INVESTMENT, AND ANNUAL REVENUE REQUIREMENTS (Continued)

Process	Energy consumption, % of input energy	Land hectares	Capital investment		Annual revenue requirements	
			10^6 $	$/kW	10^6 $	mills/kWh
Jet-bubbling limestone						
0.8% S in coal	3.4	5	42.0	84	10.9	3.7
1.4% S in coal	3.3	5	42.0	84	10.9	3.6
2.0% S in coal	3.3	5	43.8	88	11.4	3.8
3.5% S in coal	3.4	5	47.0	94	12.2	4.1
0.5% S in lignite	3.3	5	42.1	84	11.0	3.7
2.5% S in oil	2.6	5	38.5	77	10.2	3.4
Magnesium oxide						
0.8% S in coal	3.9	3	48.9	98	12.9	4.3
1.4% S in coal	4.1	3	52.0	104	13.7	4.6
2.0% S in coal	4.8	3	58.1	116	15.1	5.0
3.5% S in coal	6.3	3	68.4	137	17.5	5.9
0.5% S in lignite	3.8	3	47.1	94	12.6	4.2
2.5% S in oil	3.7	3	44.6	89	12.0	4.0
Sodium sulfate						
0.8% S in coal	4.1	3	46.8	94	12.2	4.1
1.4% S in coal	4.6	3	50.3	101	13.1	4.4
2.0% S in coal	4.7	3	56.9	114	14.8	4.9
3.5% S in coal	8.1	3	68.7	137	17.9	6.0
0.5% S in lignite	3.9	3	44.8	90	11.8	3.9
2.5% S in oil	4.5	3	44.2	88	11.8	3.9
3.5% S in coal, sulfur production	9.9	3	71.3	143	21.0	7.0
Carbon adsorption						
0.8% S in coal	0.6	5	51.2	102	13.9	4.6
1.4% S in coal	0.8	5	54.2	108	15.8	5.3
2.0% S in coal	1.0	5	60.8	122	20.0	6.7
3.5% S in coal	1.7	5	73.5	147	28.5	9.5
0.5% S in lignite	0.5	5	49.5	99	12.8	4.3
2.5% S in oil	0.9	5	53.7	107	17.5	5.9

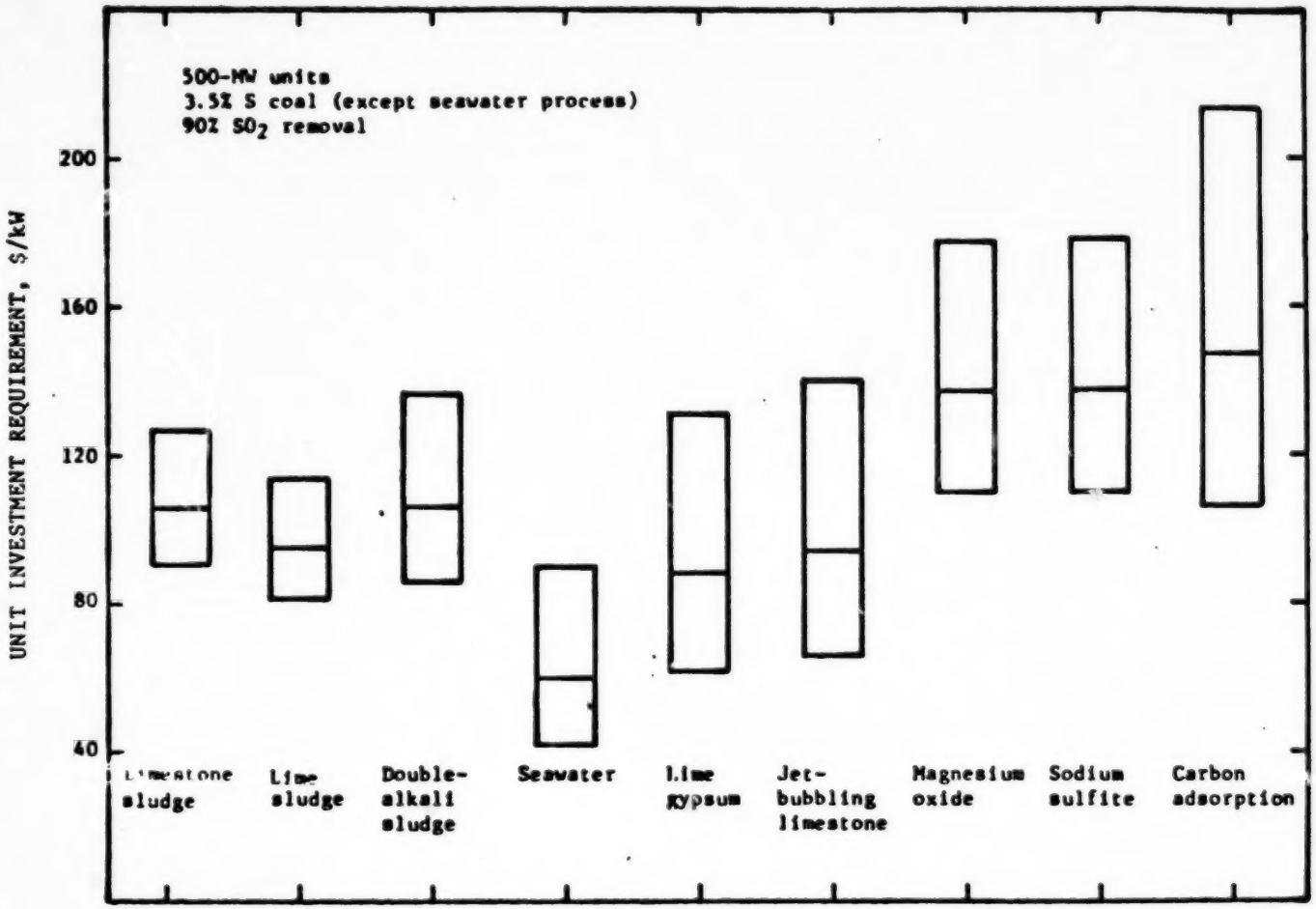


Figure 6. Base-case unit investment range for alternate processes.

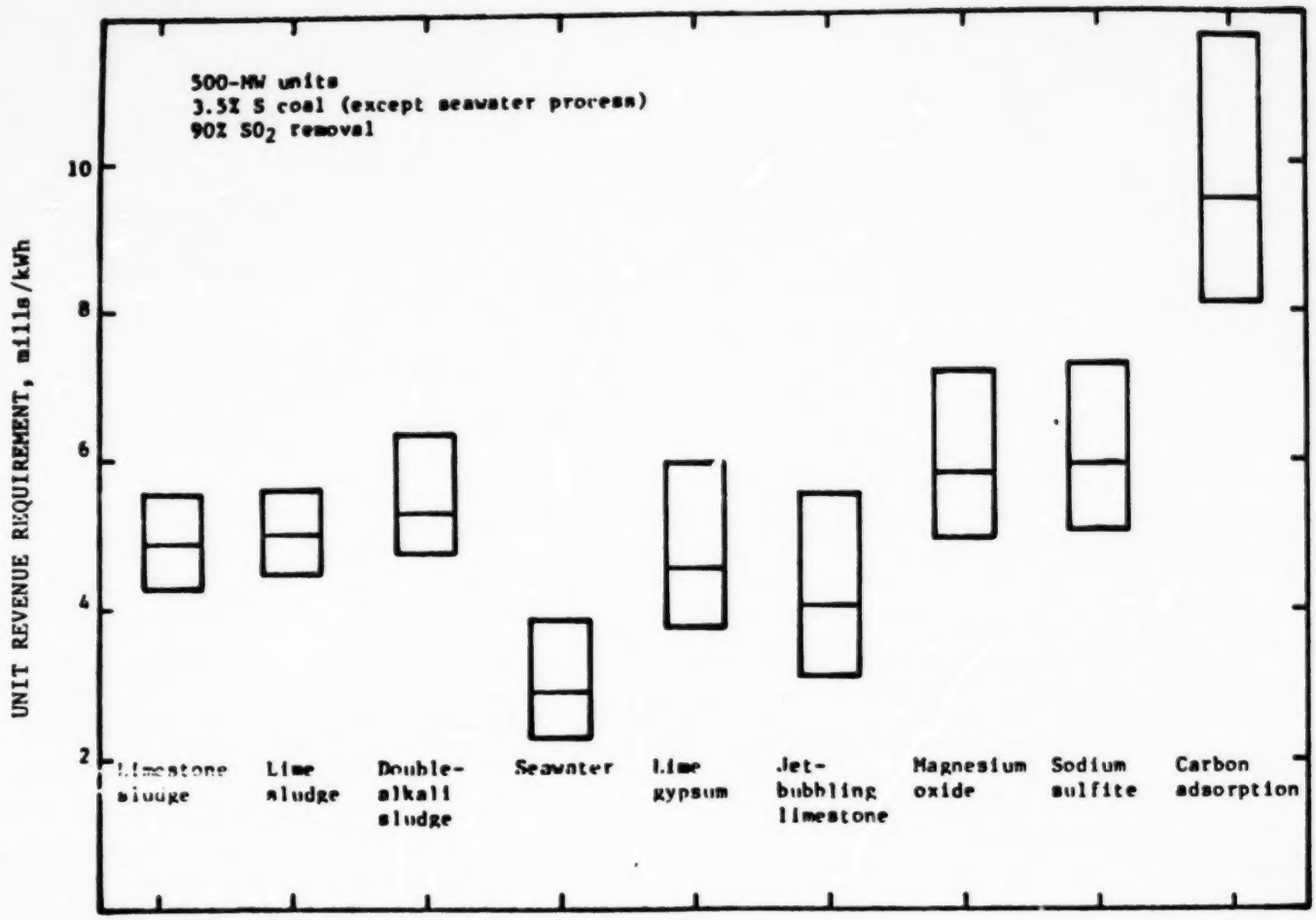


Figure 7. Base-case unit revenue requirement range for alternate processes.

Comparison of Two Cost Methods

Despite the many differences between the actual systems and the design premises used in the TVA studies, we have attempted to compare the results of the two approaches.

The capital costs for limestone and lime slurry processes are plotted against coal sulfur content with high and low accuracy ranges for the 500 MW, 90 percent SO_2 removal base case in the NATO CCMS Study, in Figures 8 and 9, respectively. Superimposed on these plots are the actual adjusted costs expressed in 1979 $, for each of the lime and limestone systems for which data exists in the FGDIS, regardless of unit capacity. Also plotted is the average value (intersection point) from the FGDIS for all of the limestone and lime slurry processes expressed in 1979 $.

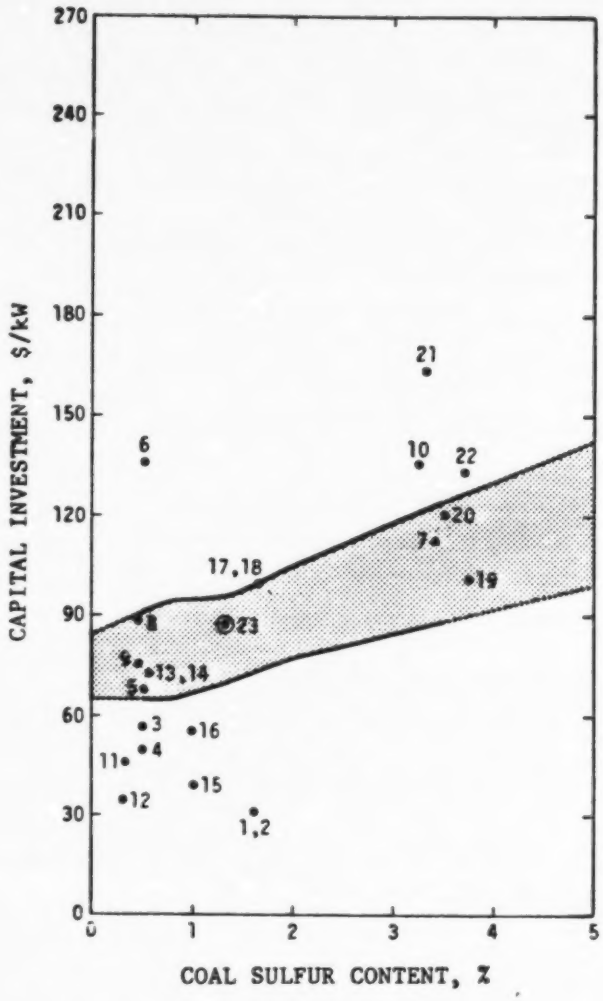
The same procedure was used in Figures 10 and 11, for the annual revenue requirement comparisons for limestone and lime slurry processes, respectively. Here the average values for the adjusted real costs did not fall within the shaded area, but were somewhat high. Investigation of some of the specific high values (e.g., Duquesne Light Co., Phillips and Elrama; Springfield Water, Light and Power, Dallman; and Indianapolis Power & Light, Petersburg) for annual revenue requirements yielded several recurrent reasons for abnormally high costs. Some of these are:

- Waste disposal at a distant off-site landfill; in one case a disposal fee is charged.
- Extensive modifications were made to the systems, after the system was in operation. These modifications were charged to annual costs, or at least, added to capital, thus raising annual revenue requirements due to amortization of costs.
- Unusually expensive materials of construction due to special application such as high-chloride coal.

Since these factors were not part of the TVA premises, it is understandable that the resulting actual costs are higher than the TVA design model costs.

To put FGD costs in perspective, it is useful to compare them to costs for coal-fired power plants. We estimate that the capital cost and annual revenue requirement for such an uncontrolled plant are $710/kW and 39 mills/kWh in 1979 $, respectively. Thus, based on the TVA design model, the cost of a limestone FGD system is about 13 percent of the total cost of the FGD controlled power plant; and the FGD annual revenue requirement is about 11 percent of the controlled plant revenue requirement.

NOTE: Recently, TVA justified revision of their previous design and economic premises based on changing economic conditions, fuel use patterns, developments in economic evaluation techniques, developments in FGD technology, and environmental legislation. The new premises are generally more conservative, and result in capital costs and annual revenue requirements, which are almost double what they were under the old premises. A discussion of the "new" vs "old" premises is given in, FGD Economics in 1980.[4]



LEGEND

Alabama Electric
(1) Tombigbee 2
(2) Tombigbee 3

Arizona Electric Power
(3) Apache 2
(4) Apache 3

Arizona Public Service
(5) Cholla 1
(6) Cholla 2

Central Illinois Light
(7) Duck Creek 1

Colorado Ute Electric
(8) Craig 1
(9) Craig 2

Indianapolis Power & Light
(10) Petersburg 3

Kansas Power & Light
(11) Jeffrey 1
(12) Jeffrey 2

Salt River Project
(13) Coronado 1
(14) Coronado 2

South Carolina Public Service Authority
(15) Winyah 2
(16) Winyah 3

South Mississippi Electric
(17) R D Morrow 1
(18) R D Morrow 2

Southern Illinois Power Co-op
(19) Marion 4

Springfield City Utilities
(20) Southwest 1

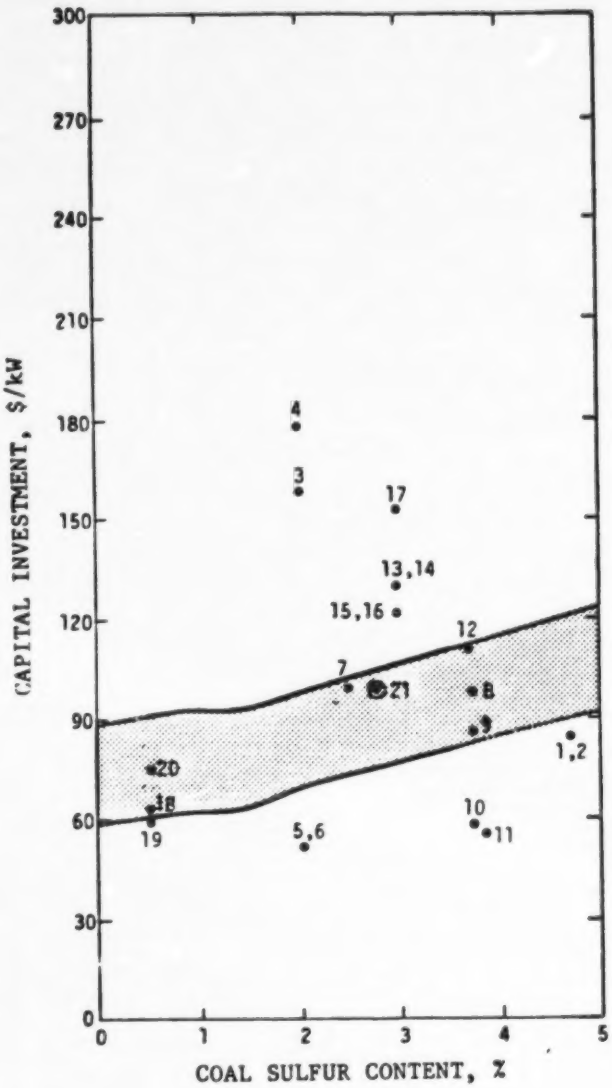
Springfield Water, Light & Power
(21) Dallman 3

Tennessee Valley Authority
(22) Widows Creek 8

(23) Intersection point of average capital investment and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 281 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1979 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 8. Limestone FGD capital cost comparison, adjusted actual vs modeled.



LEGEND

Columbus & Southern Ohio Electric
(1) Conesville 5
(2) Conesville 6

Duquesne Light
(3) Elrama 1-4
(4) Phillips 1-6

Kansas City Power & Light
(5) Hawthorne 3
(6) Hawthorne 4

Kentucky Utilities
(7) Green River 1-3

Louisville Gas & Electric
(8) Cane Run 4
(9) Cane Run 5
(10) Mill Creek 1
(11) Mill Creek 2
(12) Paddys Run 6

Monongahela Power
(13) Pleasants 1
(14) Pleasants 2

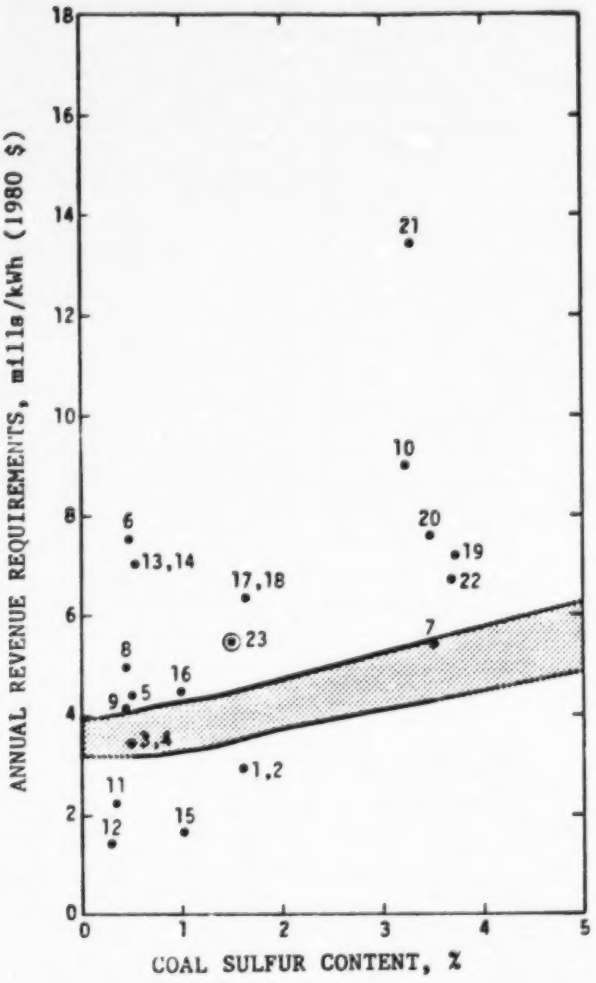
Pennsylvania Power
(15) Bruce Mansfield 1
(16) Bruce Mansfield 2
(17) Bruce Mansfield 3

Utah Power & Light
(18) Hunter 1
(19) Hunter 2
(20) Huntington 1

(21) Intersection point of average capital investment and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 416 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1979 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 9. Lime FGD capital cost comparison, adjusted actual vs modeled.



LEGEND

Alabama Electric
(1) Tombigbee 2
(2) Tombigbee 3

Arizona Electric Power
(3) Apache 2
(4) Apache 3

Arizona Public Service
(5) Cholla 1
(6) Cholla 2

Central Illinois Light
(7) Duck Creek 1

Colorado Ute Electric
(8) Craig 1
(9) Craig 2

Indianapolis Power & Light
(10) Petersburg 3

Kansas Power & Light
(11) Jeffrey 1
(12) Jeffrey 2

Salt River Project
(13) Coronado 1
(14) Coronado 2

South Carolina Public Service Authority
(15) Winyah 2
(16) Winyah 3

South Mississippi Electric
(17) R D Morrow 1
(18) R D Morrow 2

Southern Illinois Power Co-op
(19) Marion 4

Springfield City Utilities
(20) Southwest 1

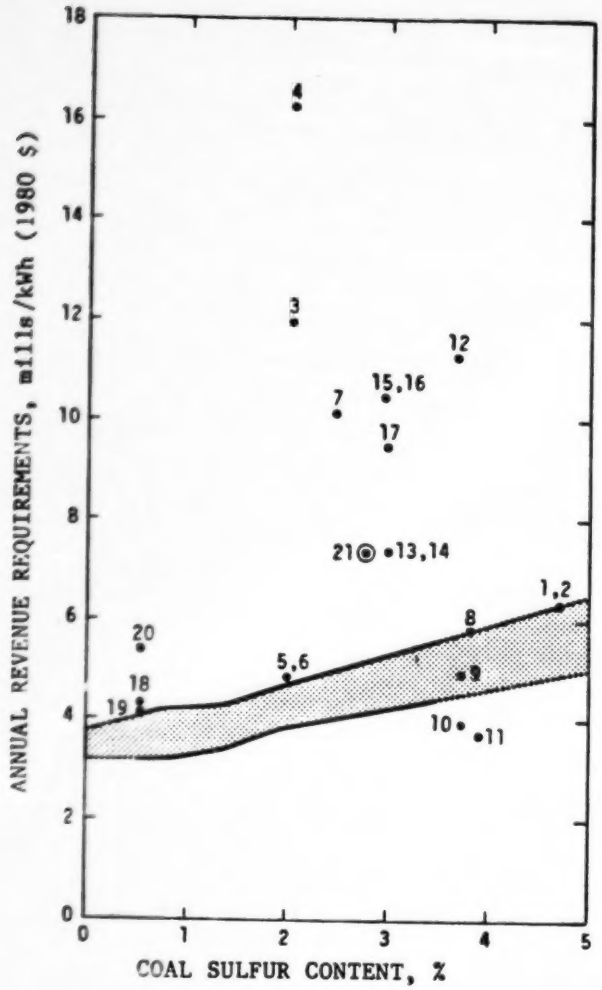
Springfield Water, Light & Power
(21) Dallman 3

Tennessee Valley Authority
(22) Widows Creek 8

(23) Intersection point of average annual revenue requirements and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 281 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1980 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 10. Limestone FGD annual revenue requirements comparison, adjusted actual vs modeled.



LEGEND

Columbus & Southern Ohio Electric
(1) Conesville 5
(2) Conesville 6

Duquesne Light
(3) Elrama 1-4
(4) Phillips 1-6

Kansas City Power & Light
(5) Hawthorne 3
(6) Hawthorne 4

Kentucky Utilities
(7) Green River 1-3

Louisville Gas & Electric
(8) Cane Run 4
(9) Cane Run 5
(10) Mill Creek 1
(11) Mill Creek 2
(12) Paddys Run 6

Monongahela Power
(13) Pleasants 1
(14) Pleasants 2

Pennsylvania Power
(15) Bruce Mansfield 1
(16) Bruce Mansfield 2
(17) Bruce Mansfield 3

Utah Power & Light
(18) Hunter 1
(19) Hunter 2
(20) Huntington 1

(21) Intersection point of average annual revenue requirements and average coal sulfur content (Average equivalent scrubbed capacity of units plotted is 416 MW)

NOTE: Shaded region above is based on TVA cost projections for new 500 MW units in common 1980 dollars, as reported in "NATO/CCMS Flue Gas Desulfurization Pilot Study, Phase II, August 1980."

Figure 11. Lime FGD annual revenue requirements comparison, adjusted actual vs modeled.

References

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4. McGlamery, G.G., W.E. O'Brien, C.D. Stephenson, and J.D. Veitch. FGD Economics in 1980. Published in Proceedings: Symposium on Flue Gas Desulfurization - Houston, October 1980; Volume 1, pp. 49-83, EPA-600/9-81-019a, NTIS No. PB 81-243156, U.S. EPA, Industrial Environmental Research Laboratory, Research Triangle Park, NC, April 1981.